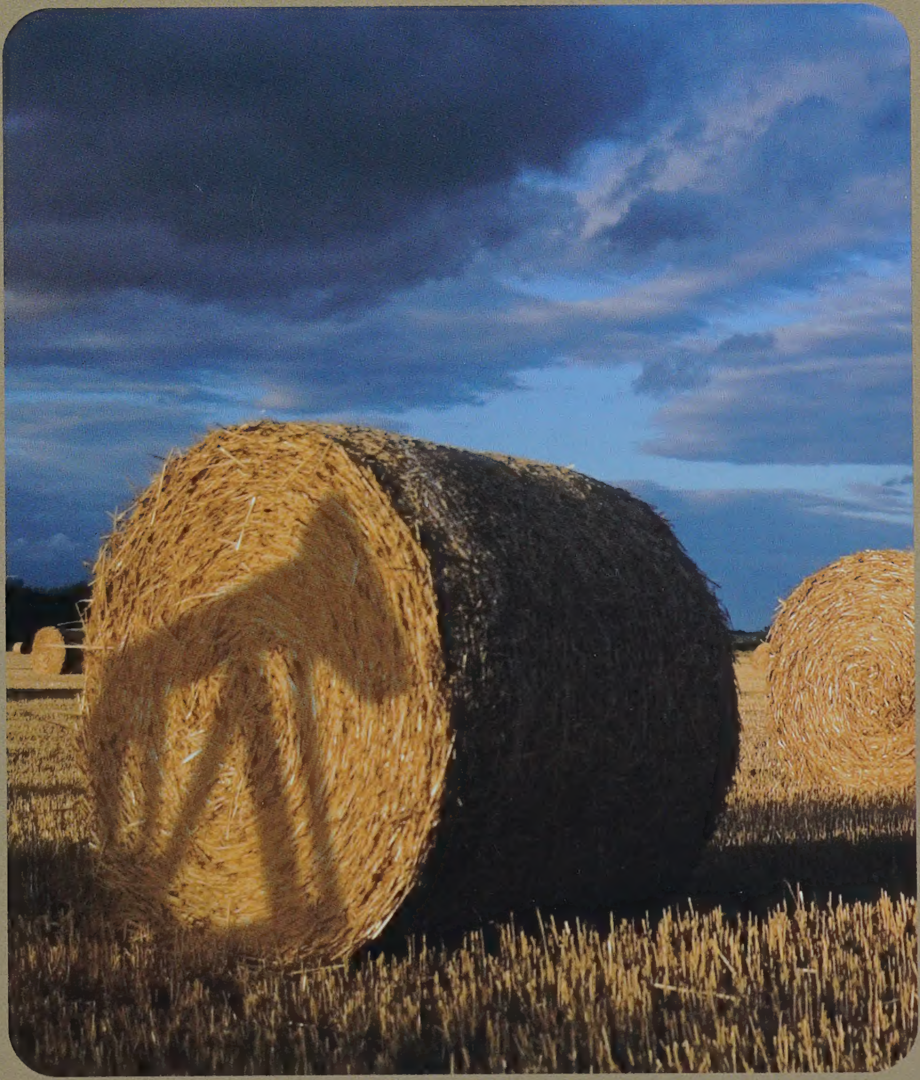
Bonterra
Energy Income Trust

2006 ANNUAL REPORT



Bonterra Energy Income Trust (TSX symbol - BNE.UN) is an energy income trust that develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan.

The Trust's business strategy is to strive to maximize Unitholder's value by applying long-term growth objectives. The Trust's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for our Unitholders.

Contents

Notice of Annual General Meeting The Annual General Meeting of Unitholders will be held on Thursday, May 24, 2007, in the Nakiska Room at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

Forward-Looking Information

Certain information set forth in this document, including management's assessment of Bonterra Energy Income Trust's. ("the Company" or "Bonterra") future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Bonterra's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Bonterra's actual results, performance or achievement could differ materially from those expressed in, or implied by these forward-looking statements, and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Bonterra will derive there from. Bonterra disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that net present value of reserves does not represent fair market value of reserves.

Highlights	**2006**	2005	2004
Financial ($000, except $ per unit)			
Revenue – oil and gas	**88,734**	75,837	53,585
Distributions per Unit	**2.82**	2.37	1.88
Funds flow from Operations [1]	**52,797**	44,579	29,609
Per Unit Basic	**3.15**	2.72	2.08
Per Unit Fully Diluted	**3.12**	2.69	2.03
Distributable cash [2]	**34,164**	29,132	25,824
Per Unit Basic	**2.04**	1.78	1.82
Per Unit Fully Diluted	**2.02**	1.76	1.77
Net Earnings	**37,250**	33,468	20,366
Per Unit Basic	**2.23**	2.04	1.43
Per Unit Fully Diluted	**2.21**	2.01	1.40
Capital Expenditures and Acquisitions [3]	**38,348**	56,703	10,595
Working Capital Deficiency	**50,187**	21,972	8,948
Unitholders' Equity	**53,359**	57,322	54,060
Units Outstanding (000's)	**16,875**	16,535	14,943
Operations			
Oil and Liquids (barrels per day)	**3,040**	2,713	2,361
Average Price ($ per barrel)	**64.69**	58.30	47.30
Natural Gas (MCF per day)	**6,014**	5,650	4,996
Average Price ($ per MCF)	**7.55**	8.64	6.81
Total barrels per day (BOE per day) [4]	**4,042**	3,655	3,194
Reserves			
Oil and Liquids (barrels in 000's)			
Proved Developed Producing (Gross) [5]	**13,688**	13,840	11,956
Proved (Gross)	**16,758**	15,662	12,832
Proved plus Probable (Gross)	**21,526**	19,606	16,084
Natural Gas (MCF in 000's)			
Proved Developed Producing (Gross)	**17,011**	17,518	17,021
Proved (Gross)	**22,562**	20,473	18,288
Proved plus Probable (Gross)	**29,700**	25,582	21,762
Reserve Life Index (Oil, liquids and natural gas @ 6:1) [6]			
Proved Developed Producing	**11.0**	12.1	12.4
Proved	**13.6**	13.8	13.3
Proved plus Probable	**17.6**	17.3	16.5
Reserves in BOE's per Weighted Outstanding Unit			
Proved Developed Producing	**0.98**	1.02	1.04
Proved	**1.22**	1.16	1.12
Proved plus Probable	**1.57**	1.46	1.39

(1) Funds flow from operations is not a recognized measure under GAAP. Management believes that in addition to net earnings, funds flow from operations is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers.For these purposes, the Trust defines funds flow from operations as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement expenditures.

(2) The computation and disclosures of Distributable Cash is in all material respects, except that only fiscal year 2006, 2005 and 2004 information is provided, with the guidance provided in CICA's publication "Distributable Cash in Income Trusts and Other Flow-Through Entities – Guidance on Preparation and Disclosure in Management's Discussion and Analysis – An Interpretive Release."

(3) Capital expenditures and acquisitions include the purchase of Novitas Energy Ltd. (Novitas) on January 7, 2005. The Trust issued 1,335,753 units at a value of $25 per unit plus paid $769,000 in cash for all of the issued and outstanding common shares of Novitas. For accounting purposes the transaction was recorded at the cost of the Novitas' assets and liabilities due to Novitas being considered a related party to the Trust.

(4) BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

(5) Gross reserves relate to the Trusts ownership of reserves before royalty interests.

(6) The reserve life index is calculated by dividing the reserves (in BOE's) by the annualized fourth quarter average production rate in BOE/d (2006 – 4,119, 2005 – 3,780).

Report to Unitholders

Bonterra Energy Income Trust ("Bonterra" or the "Trust") is pleased to report its operational and financial results for the year. It has generally been a successful year with the exception of the announced potential Federal changes to taxation of trusts as disclosed on October 31, 2006, which has had a severe impact on unit prices for trusts. In 2006 Bonterra was successful in increasing on a per unit basis its oil and natural gas reserves, its distributions to Unitholders, its net earnings, its funds flow, and its daily production.

Bonterra's ability to increase annual results on a per unit basis continues to be of prime importance. A continued above average return to the Trust's investors is the main objective. Please refer to page one of this annual report for highlights of various specific results.

2006 and 2007 Capital Spending and Production

In 2006 Bonterra's capital budget was $38,000,000. The Trust drilled 43 gross (30.3 net) Cardium oil wells (all successful). The Trust also drilled 18 gross (15.3 net) Edmonton Sand shallow gas wells (7 of which have been determined to be uneconomic and have been written-off).

At December 31, 2006, Bonterra had an inventory of wells drilled in 2006 but not on production, of 21 gross (11.4 net) Cardium oil wells (including 9 gross, 1.3 net, on non-operated lands), 12 gross (9.3 net) natural gas wells and 7 gross (5.5 net) coal-bed wells.

Most of these wells will be on production during the first half of 2007, with the exception of the coal-bed wells. The coal-bed wells will be completed after regulatory decisions have been finalized.

Due mainly to verification and clarity with regard to taxation of income trusts by the Federal government, the 2007 capital budget has been reduced to $20,000,000 and most of this capital will be spent in the first half of 2007, allowing time to get the wells on production in 2007. The 2007 wells and the completion in 2007 of the inventory of uncompleted 2006 wells should result in a similar number of completed wells in 2007 as in 2006 despite the reduction of expenditures from $38,000,000 in 2006 to $20,000,000 in 2007.

Average production in 2006 increased to 4,042 BOE per day from 3,655 BOE per day in 2005. It is expected that average production may increase in 2007.

Reserves

Gross proved plus probable crude oil and NGL reserves increased by 9.8 percent and gross proved plus probable natural gas reserves increased by 16.1 percent in 2006 compared to 2005. The reserve life index increased to 17.6 years from 17.3 years in 2005. On a per unit basis the reserves in BOE per weighted average outstanding unit increased to 1.57 in 2006 from 1.46 in 2005.

Bank Debt

The aggressive capital budget of $38,000,000 in 2006 resulted in an increase of bank debt to $45,379,000 compared to $20,177,000 in 2005, representing a debt to annual funds flow of approximately 11 months. It is anticipated that this ratio will be reduced in 2007.

Cash Netback

Bonterra's cash netback was $35.04 in 2006 compared to $32.86 in 2005 due mainly to higher average costs of oil offset somewhat by lower natural gas prices. The netback is very sensitive to fluctuations in average commodity prices from year to year.

Return to Investors

The return to investors for 2006 from distributions and capital appreciation was 20.3 percent compared to a return of 3.5 percent in 2005. The proposed Federal tax treatment of trust distributions had a major impact upon the 2006 return. On October 31 the Trust units were trading at $37 and by December 31, 2006, the unit prices had decreased to $25. The Federal announcement likely accounts for a major portion of this decrease. Market cap for Bonterra decreased to approximately $420,000,000 on December 31, 2006, from $620,000,000 on October 31, 2006.

Despite the devaluation of the Trust unit price following the taxation announcement, the Trust's core business remains unchanged. Bonterra is currently assessing the draft legislation but is waiting for final approval of the draft legislation before deciding upon alternatives with respect to the future structure of the Trust.

Outlook

The objective for the Trust is to increase its production volumes and reserves on an annual basis by drilling its large inventory of drill locations. Subject to commodity prices this should enable the Trust to annually increase its distributions on a per unit basis.

The Board of Directors of the operating company and management wish to thank the Unitholders for their continued loyal support and advice, and also wish to thank the staff for its continued loyalty and the large contribution that is made on a continuous basis towards the success of the Trust.

Submitted on behalf of the Board of Directors

George F. Fink
President, CEO, and Director

Reserves

The Trust engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2006. The reserves are located in the Provinces of Alberta and Saskatchewan. The Trust's main oil producing areas are located in the Pembina area of Alberta, and the Dodsland and Shaunavon areas of Saskatchewan. The gross reserve figure for the following charts represents the Trust's ownership interest before royalties and the net figure is after deductions for royalties.

Summary of Oil and Gas Reserves as of December 31, 2006 (Forecast Prices and Costs)

	Reserves					
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserve Category	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved						
Developed Producing	12,934	12,269	17,011	12,675	754	536
Developed Non-Producing	391	389	2,962	2,283	27	19
Undeveloped	2,553	2,319	2,589	1,813	99	70
Total Proved	15,878	14,977	22,562	16,771	880	625
Probable	4,522	4,256	7,138	5,339	246	175
Total Proved Plus Probable	20,400	19,233	29,700	22,110	1,126	800

Reconciliation of Trust Gross Reserves by Principal Product Type (Forecast Prices and Costs)

	Light, Medium Oil and NGL's			Natural Gas		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2005	15,662	3,944	19,606	20,473	5,110	25,583
Extension	10	–	10	920	–	920
Improved recovery	1,655	643	2,298	2,687	639	3,326
Technical revisions	564	197	761	583	1,223	1,806
Discoveries	1	2	3	116	172	288
Acquisitions	16	–	16	–	–	–
Dispositions	(40)	(18)	(58)	(11)	(5)	(16)
Production	(1,110)	–	(1,110)	(2,206)	–	(2,206)
December 31, 2006	16,758	4,768	21,526	22,562	7,139	29,701

Summary of Net Present Values of Future Net Revenue as of December 31, 2006 (Forecast Prices and Costs)

	Net Present Value of Future Net Revenue Before and After Income Taxes Discounted at (%/year)				
(M$) Reserve Category	0	5	10	15	20
Proved					
Developed Producing	569,022	363,050	271,893	221,685	189,765
Developed Non-Producing	27,731	19,068	15,479	13,444	12,069
Undeveloped	46,070	34,813	26,120	19,332	13,971
Total Proved	642,823	416,931	313,492	254,461	215,805
Probable	242,903	103,837	62,670	44,553	34,337
Total Proved Plus Probable	885,726	520,768	376,162	299,014	250,142

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per barrel)	Alberta Gas Reference Price Plantgate (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn $ per barrel)
2007	74.10	7.51	43.94	55.23	75.88
2008	77.62	8.38	46.03	57.85	79.49
2009	70.25	7.55	41.66	52.36	71.94
2010	65.56	7.37	38.88	48.87	67.14
2011	61.90	7.54	36.71	46.14	63.40
2012	63.15	7.68	37.45	47.07	64.67
2013	64.42	7.79	38.21	48.02	65.98
2014	65.72	7.93	38.97	48.98	67.30
2015	67.04	8.07	39.76	49.97	68.66
2016	68.39	8.21	40.56	50.97	70.04
2017	69.76	8.54	41.38	52.00	71.45

Crude oil, natural gas and liquid prices escalate at 2% per year thereafter.

The following cautionary statements are specifically required by NI 51-101

- It should not be assumed that the estimates of future net revenue presented in the above tables represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.
- Disclosure provided herein in respect of BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6mcf:1bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

Production

The following table provides a summary of production volumes from the Trust's main producing areas:

	2006		2005	
	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)
Pembina, Alberta	**2,178**	**4,768**	1,767	4,290
Shaunavon, Saskatchewan	**348**	**–**	363	–
Dodsland, Saskatchewan	**251**	**141**	302	151
Peck Lake, Saskatchewan	**–**	**392**	–	541
Pinto, Saskatchewan	**72**	**97**	73	86
Redwater, Alberta	**36**	**73**	37	57
Midale, Saskatchewan	**40**	**8**	42	14
Other	**115**	**535**	129	511
	3,040	**6,014**	2,713	5,650

Land Holdings

The Trust's holdings of petroleum and natural gas leases and rights are as follows:

	2006		2005	
	Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**
Alberta	**119,777**	**73,431**	114,657	68,098
Saskatchewan	**63,136**	**48,538**	63,136	48,538
	182,913	**121,969**	177,793	116,636

Petroleum and Natural Gas Capital Expenditures

The following table summarizes petroleum and natural gas capital expenditures incurred by the Trust on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

	2006	2005
Acquisitions	**$ –**	$40,852,000
Exploration and development costs	**38,348,000**	15,810,000
Pipeline projects	**–**	15,000
Land costs	**–**	26,000
Net petroleum and natural gas capital expenditures	**$38,348,000**	$56,703,000

Drilling History

The following table summarizes the Trust's gross and net drilling activity and success:

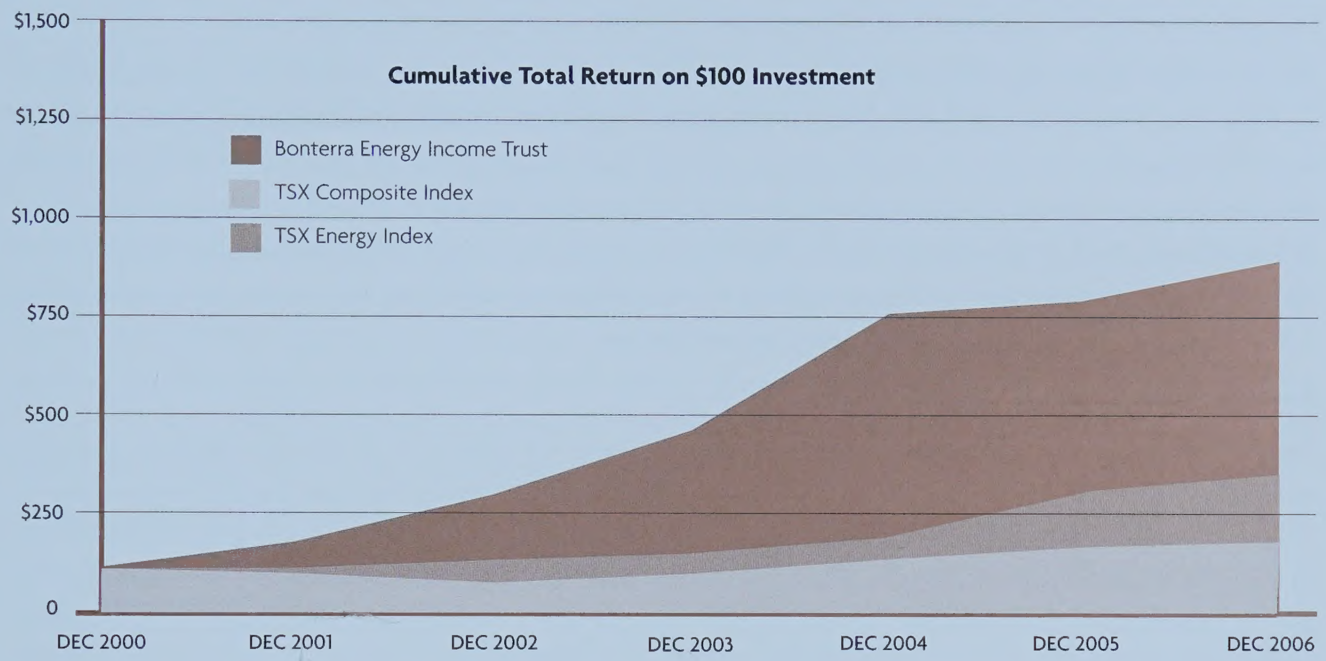
	2006					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude Oil	43	30.3	–	–	43	30.3
Natural Gas	11	8.3	–	–	11	8.3
Dry	7	7.0	–	–	7	7.0
Total	61	45.6	–	–	61	45.6
Success rate	89%	85%	–	–	89%	85%

	2005					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude Oil	42	15.0	–	–	42	15.0
Natural Gas	5	3.0	–	–	5	3.0
Dry	1	0.5	–	–	1	0.5
Total	48	18.5	–	–	48	18.5
Success rate	98%	97%	–	–	98%	97%

	2004					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude Oil	19	5.8	–	–	19	5.8
Natural Gas	19	16.6	1	1	20	17.6
Dry	4	3.8	–	–	4	3.8
Total	42	26.2	1	1	43	27.2
Success rate	90.5%	85.5%	100%	100%	90.7%	86.0%

Market Performance

The following graph illustrates changes over the past six years in the value of $100 invested in Bonterra (of Common Shares of Bonterra Energy Corp. prior to July 1, 2001 or Trust Units thereafter, as the case may be), the TSX Composite Index and the TSX Energy Index.



December,	2000	2001	2002	2003	2004	2005	**2006**
Bonterra Energy Income Trust[1]	$100	$168	$293	$476	$757	$779	**$896**
TSX Composite Index	$100	$86	$74	$92	$104	$126	**$144**
TSX Energy Index	$100	$102	$115	$142	$183	$292	**$296**

Note 1: Includes distributions of $10.85 per Unit since becoming a Trust.

Trust Unit Trading Statistics

Unit Prices (based on daily closing price)	**2006**	2005
High	**$37.85**	$25.97
Low	**$23.60**	$20.00
Close	**$25.57**	$23.60
Daily Average Trading Volume	**31,417**	26,487

Property Discussions

Bonterra has an excellent asset base consisting of concentrated, stable and under-developed properties with large amounts of remaining oil in place, a long reserve life, with low risk and predictable reserves. Management feels that the stable asset base with its predictable production profile represents the most suitable reserve base for a trust. The high wellhead prices received for Bonterra's production and the low royalty rates paid equates to Bonterra having among the highest netbacks in the industry. Management has continually proven it can manage these high quality assets to generate long-term value.

The Trust's major producing properties are located in the Pembina area of Alberta, the Dodsland and Shaunavon areas in southwest Saskatchewan, and the southeast area of Saskatchewan. Bonterra's reserves and production growth will come from exploiting its remaining oil in place properties primarily from its large inventory of low risk internally generated exploitation and drilling programs that have predictable results. The Trust will continue to maintain its financial flexibility so it can continue to acquire exploration and development lands in the Pembina area of Alberta, and pursue other drilling opportunities in Alberta and Saskatchewan. The Trust will be reviewing and assessing strategic producing and non-producing properties for acquisitions on an ongoing basis in various areas in Western Canada.

Pembina Area, West Central Alberta

The Pembina field is the largest conventional oil field in Canada and contains the Trust's most significant producing property. Pembina is Bonterra's largest core area representing 81.3% of the Trust's total reserves. The high concentration of interest in a single area allows for better focused management of these assets including an improved ability to manage cost and efficiently invest capital. This production is predominately predictable, long life, low decline, and high quality light oil and associated liquid-rich solution gas from the Cardium formation that is located at an average depth of approximately 1,550 meters.

Bonterra operates approximately 85 percent of its production which allows for significant operating efficiencies. The property contains approximately 400 gross (320 net) operated producing wells with an 80 percent average working interest and 177 gross (29 net) non-operated producing wells with an approximate 16 percent average working interest.

This large land holding, large amount of remaining oil in place, and strong infrastructure position provides a strong base to exploit a range of low risk development and exploration opportunities. Even though the Pembina area is considered a mature field it is proving to be a significant area for multi-zone oil and natural gas exploration with predictable results. The Trust has managed to increase reserves in the area through optimization and drilling as well as through key acquisitions. As a result, Bonterra has one of the longest Reserve Life Indexes and a proven record of production and reserves replacement through drilling and improved recovery.

The Trust's large drilling inventory has enabled it to increase production volumes. A Cardium infill drilling program was initiated on Bonterra's non-operated properties in 2003 and on operated properties in 2004 and has continued successfully through 2006 and will continue in 2007. Most operators in the Pembina area have reduced well spacing to 40 acres; whereas, Bonterra is generally reducing its spacing to 80 acres and to 40 acres only where proven successful in not affecting offsetting production. The continuation of the Cardium drilling program will allow the Trust to maintain and increase its production rates and reserves.

Bonterra has significant potential upside in the Pembina Cardium with the potential implementation of a miscible CO_2 enhanced oil recovery scheme. There is significant uncertainty over the economic feasibility of enhanced oil recovery using

CO_2 however an industry operator is currently running a miscible CO_2 flood pilot offsetting Bonterra lands. Details of the pilot are confidential; however, public information released by the operator is encouraging. Increasing environmental concern over CO_2 emissions and the current high price environment are improving the viability of CO_2 flooding, however a long term low cost source of CO_2 and supportive environmental regulations will be key to its implementation. The Trust has a large land base that may be suitable for CO_2 enhanced oil recovery and will continue to investigate its potential development.

Bonterra is also producing from the Belly River formation. The Belly River produces high quality light sweet oil from a depth of approximately 1,100 meters. There is potential to increase production from the Belly River formations through drilling in select areas of the field.

Bonterra has been able to increase natural gas production and reserves by drilling multi-zone shallow gas wells into the Edmonton and Paskapoo formations. The Trust is targeting several productive sands that range in depth from 275 to 850 meters. Bonterra continued to drill wells on its expanded shallow gas land base in 2006 with the wells being further removed from existing production. Several of the wells from last year's program were not completed, tested or tied in at the end of the year due to timing, weather, or surface access issues. Additional gas production will be obtained in 2007 from these wells. The Trust will still see increases in gas production and reserves from the completion of last year's drilling program, selective drilling and the re-completion and optimization of existing producing wells.

Bonterra has been assessing production of natural gas from coals (NGC) in the Pembina area with encouraging initial results. Based on these results, Bonterra had hoped to proceed with a program of re-entering existing wells and drilling new wells to further assess the NGC potential. Due to regulatory delays, uncertainty by regulators, and high costs of services, Bonterra has delayed this project until all regulatory concerns are rectified. Bonterra has extensive prospective land holdings near existing operated infrastructure in the area. NGC has the potential to add significant low risk production and reserves and the Trust will continue to pursue this opportunity.

Bonterra's capital budget for 2007 is $20,000,000 compared to $38,000,000 in 2006. This will result in a reduction in wells drilled, but may not result in a reduction of wells placed on production since at December 31, 2006, the Trust had an inventory of 21 gross (11.4 net) Cardium oil wells (including 9 gross, 1.3 net on non operated lands), 12 gross (9.3 net) natural gas wells and 7 gross (5.5 net) coal-bed wells drilled but not on production. In 2007 most of the drilling will be completed in the first half of the year and therefore most wells should be on production before December 2007.

Dodsland Area, Southwest Saskatchewan

The Dodsland properties produce light sweet gravity oil and solution gas from the Viking formation at a depth of approximately 700 meters. Bonterra now operates approximately 425 gross (374 net) wells with an average working interest of 88 percent.

This is low rate stable production so cost control and hedge programs are important focuses of the operating strategy in this area. The Trust is continually reviewing different operating practices and improved technology that may improve the profitability of the property. Bonterra does not have an abandonment or reclamation liability for the majority of this property because under terms of an agreement Bonterra has an option to transfer uneconomic wells to the previous owner of the property.

Southeast Saskatchewan

The southeast properties produce slightly sour high gravity oil and solution gas primarily from the Midale formation. The Trust has an average working interest of approximately 98 percent of its properties in the area. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability of the properties. Some of these properties are located close to fields that have extensive CO_2 flood programs; and therefore, in the future may be conducive to reserve and production increases from a CO_2 flood program.

Shaunavon Area, Southwest Saskatchewan

Bonterra operates this producing property which consists of approximately 50 producing wells in the Shaunavon area of southwest Saskatchewan where the Trust's working interest averages approximately 92 percent. The properties are located in the Whitemud and Chambery fields and produce 22 degree API crude oil from the upper Shaunavon formation located at a depth of approximately 1,500 meters. A portion of the property is being produced under waterflood with the majority of the properties still on primary production. The primary production areas are being monitored on an ongoing basis to determine if waterflood programs should be initiated. The wells in the Shaunavon area generally have a very long life and stable low production decline profile after a short period of higher decline when a new well initially commences production.

The Trust is continuing to assess its undeveloped acreage to determine if there is potential exploration or development prospects in the area.

Other

Bonterra has varying interests in other producing and non-producing properties in various other areas of Alberta and Saskatchewan. Most of these properties are long term producers and may provide opportunities for increased interests in the future.

Management's Discussion and Analysis

This report dated March 16, 2007, is a review of the operations, current financial position and outlook for the Trust, and should be read in conjunction with the audited financial statements for the year ended December 31, 2006, together with the notes related thereto.

Forward-looking Information

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, statements relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash distributions; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas trusts to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive and are further discussed herein under the heading Business Prospects, Risks and Outlooks as well as in the Trust's Annual Information Form filed on SEDAR at www.sedar.com.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

Annual Comparisons

	2006	2005	2004
Financial ($000, except $ per unit)			
Revenue – oil and gas	**88,734**	75,837	53,585
Funds Flow from Operations [1]	**52,797**	44,579	29,606
Per Unit Basic	**3.15**	2.72	2.08
Per Unit Fully Diluted	**3.12**	2.69	2.03
Distributable Cash from Operations [2]	**34,164**	29,132	25,824
Per Unit Basic	**2.04**	1.78	1.82
Per Unit Fully Diluted	**2.02**	1.76	1.77
Net Earnings	**37,250**	33,468	20,366
Per Unit Basic	**2.23**	2.04	1.43
Per Unit Fully Diluted	**2.21**	2.01	1.40
Cash Distributions per Unit	**2.82**	2.37	1.88
Capital Expenditures and Acquisitions	**38,348**	56,703	10,943
Total Assets	**134,942**	110,149	84,989
Working Capital Deficiency	**50,187**	21,972	8,948
Unitholders' Equity	**53,359**	57,322	54,060
Operations			
Oil and Liquids (barrels per day)	**3,040**	2,713	2,361
Natural Gas (MCF per day)	**6,014**	5,650	4,996

Quarterly Comparisons

	2006			
	4th	**3rd**	**2nd**	**1st**
Financial ($000, except $ per unit)				
Revenue – oil and gas	21,719	23,665	23,219	20,131
Funds Flow from Operations [1]	12,235	14,401	14,008	12,153
Per Unit Basic	0.72	0.86	0.84	0.73
Per Unit Fully Diluted	0.72	0.85	0.83	0.72
Net Earnings	6,471	10,441	10,617	9,721
Per Unit Basic	0.39	0.62	0.64	0.58
Per Unit Fully Diluted	0.38	0.62	0.63	0.58
Cash Distributions	0.72	0.72	0.69	0.69
Capital Expenditures and Acquisitions	9,457	12,597	6,246	10,048
Total Assets	134,942	130,655	122,166	118,439
Working Capital Deficiency	50,187	38,853	28,820	25,532
Unitholders' Equity	53,359	60,387	61,202	61,365
Operations				
Oil and Liquids (barrels per day)	3,138	3,024	3,001	2,996
Natural Gas (MCF per day)	5,885	5,925	6,181	6,071

	2005			
	4th	**3rd**	**2nd**	**1st**
Financial ($000, except $ per unit)				
Revenue – oil and gas	21,753	20,532	17,114	16,438
Funds Flow from Operations (1)	12,489	12,209	10,167	9,714
Per Unit Basic	0.76	0.75	0.62	0.59
Per Unit Fully Diluted	0.76	0.74	0.61	0.58
Net Earnings	9,918	9,309	7,115	7,126
Per Unit Basic	0.59	0.57	0.44	0.44
Per Unit Fully Diluted	0.59	0.56	0.43	0.43
Cash Distributions	0.68	0.60	0.55	0.54
Capital Expenditures and Acquisitions	10,760	3,022	678	42,243
Total Assets	110,149	101,008	99,914	102,088
Working Capital Deficiency	21,972	10,920	11,379	11,896
Unitholders' Equity	57,322	60,662	60,467	61,985
Operations				
Oil and Liquids (barrels per day)	2,814	2,680	2,635	2,724
Natural Gas (MCF per day)	5,795	5,692	5,462	5,649

(1) Funds flow from operations is not a recognized measure under GAAP. Management believes that in addition to net earnings, funds flow from operations is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines funds flow from operations as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement expenditures.

(2) The computation and disclosures of Distributable Cash in this MD&A is in all material respects, except that only fiscal year 2006, 2005 and 2004 information is provided, with the guidance provided in CICA's publication "Distributable Cash in Income Trusts and Other Flow-Through Entities – Guidance on Preparation and Disclosure in Management's Discussion and Analysis – An Interpretive Release."

Disclosure Controls and Procedures

Disclosure controls and procedures are defined under Multilateral Instrument 52-109 – Certification of Disclosure Controls in Issuers' Annual and Interim Filings ("MI 52-109") as "... controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under provincial and territorial securities legislation is recorded, processed, summarized and reported within the time periods specified in the provincial and territorial securities legislation and include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under provincial and territorial securities legislation is accumulated and communicated to the issuer's management, including its chief executive officers and chief financial officers (or persons who perform similar functions to a chief executive officer or a chief financial officer), as appropriate to allow timely decisions regarding required disclosure." The Trust has conducted a review and evaluation of its disclosure controls and procedures, with the conclusion that as at December 31, 2006 the Trust has an effective system of disclosure controls and procedures as defined under MI 52-109. In reaching this conclusion, the Trust recognizes that two key factors must be and are present:

1. the Trust is very dependent upon its advisors and consultants (principally its legal counsels) to assist in recognizing, interpreting, understanding and complying with the various securities regulations disclosure requirements; and
2. an active Board and management with open lines of communications.

The Trust has a small staff with varying degrees of knowledge concerning the various regulatory disclosure requirements. In many circumstances, the various regulatory requirements are relatively new, subject to interpretation, and complex. The Trust is not of sufficient size to justify a separate department or one or more staff member specialists in this area. Therefore the Trust must rely upon its advisors/consultants to assist it and as such they form part of the disclosure controls and procedures.

Proper disclosure necessitates that a person not only be aware of the pertinent disclosure requirements, but must also be sufficiently involved in the affairs of the Trust and/or receives the communication of information to assess any necessary disclosure requirements. Accordingly, it is essential that there be proper communication among those people who manage and govern the affairs of the Trust, this being the Board of Directors and senior management. The Trust believes this communication exists.

While the Trust believes it has adequate disclosure controls and procedures in place, lapses in the disclosure controls and procedures could occur and/or mistakes could happen. Should such occur, the Trust intends to take whatever steps it deems necessary to minimize the consequences thereof.

Internal Controls Over Financial Reporting

Internal controls over financial reporting are defined in MI 52-109 as "...a process designed by, or under the supervision of, the issuer's chief executive officers and chief financial officers, or persons performing similar functions, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

1. pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;
2. provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and
3. provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements."

The Trust has conducted a review and evaluation of its internal controls over financial reporting, with the conclusion that as of December 31, 2006 the Trust's system of internal controls over financial reporting as defined under MI 52-109 is adequately designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. In its evaluation, the Trust identified certain material weaknesses in internal controls over financial reporting:

1. due to the limited number of staff at the Trust, it is not feasible to achieve the complete segregation of incompatible duties; and
2. due to the limited number of staff, the Trust relies upon third parties as participants in the Trust's internal controls over financial reporting.

The Trust believes these weaknesses are mitigated by: the active involvement of senior management and the board of directors in the affairs of the Trust; open lines of communication within the Trust; the present levels of activities and transactions within

the Trust being readily transparent; the thorough review of the Trust's financial statements by management, the board of directors and by the Trust's auditors (annual statements only); and the establishment of a whistle-blower policy. However, these mitigating factors will not necessarily prevent a material misstatement occurring as a result of the aforesaid weaknesses in the Trust's internal controls over financial reporting. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met.

Production

The Trust's 2006 average production of oil and natural gas liquids was 3,040 (2005 – 2,713) barrels per day and natural gas production in 2006 averaged 6,014 (2005 – 5,650) MCF per day. Oil production increased by approximately 12 percent while gas production increased by approximately 6 percent. The increases were predominantly due to the Trusts 2005 and 2006 development programs. The Trust's fourth quarter production saw increases in both crude oil and natural gas production due to commencement of production from new wells drilled in 2006.

The Trust's overall annual decline rate for 2006 is approximately nine percent which the Trust was able to more than offset with its 2006 drill program. The Trust, along with its partners, drilled 43 gross (30.3 net) Cardium oil wells. This includes 34 gross and 29 net Cardium wells drilled directly by the Trust. Also the Trust drilled 18 gross (15.3 net), including one gross and .6 net drilled by a partner of the Trust, shallow gas wells in 2006. The Trust experienced a 100 percent success rate with its and its partners Cardium drilling program. The drilling of the shallow gas wells resulted in 11 successful (8.3 net) and 7 gross and net wells that have been determined to be uneconomic. The expenditures to drill these uneconomic wells totalled $2,919,000 which has been written off as dry hole costs.

As at December 31, 2006 Bonterra had 21 gross (11.4 net) Cardium oil wells (including 9 gross, 1.3 net on non operated lands), 12 gross (9.3 net) natural gas wells and 7 gross (5.5 net) coal-bed wells drilled but not on production. During the fourth quarter the Trust tied-in 11 gross (10.4 net) Cardium wells and 1 (1 net) natural gas well on its operated lands.

Subsequent to December 31, 2006 and up to the date of this report, Bonterra has put on production 6 gross (5.8 net) of it's operated Cardium oil wells and 2 gross (1 net) shallow gas wells. Most of the 9 gross (1.3 net) wells on non-operated lands also have been completed in Q1, 2007. Trust is currently completing several of its Edmonton sand gas wells drilled in 2006 and anticipates that the majority of the gas wells will be on production by the end of the second quarter of 2007. Bonterra is waiting on final regulatory decisions and recovery in natural gas pricing prior to commencing further completion work on the coal-bed methane wells.

Revenue

Gross revenue from petroleum and natural gas sales prior to royalties was $88,734,000 (2005 - $75,837,000). The increase of $12,897,000 was due to increased production volumes and an increase in the average price received for crude oil offset partially by a 12.6 percent decline in the average price of natural gas. The price received for crude oil increased to $64.69 per barrel in 2006 from $58.30 per barrel in 2005 while natural gas prices decreased to $7.55 per MCF in 2006 from $8.64 per MCF in 2005. Part of the increase in average price of crude oil was the increased production related to the Trust's light sweet crude production in the Pembina area of Alberta which receives a higher price per barrel. The mix of light crude to mid grade crude has increased to 87 percent of the Trust's crude oil production in 2006 from 85 percent in 2005

The fourth quarter saw a decrease in gross revenues of $1,946,000 over quarter three due primarily to decreased crude oil

prices. The average price received in the fourth quarter for crude oil and natural gas liquids was $60.79 ($71.11 third quarter) per barrel and $7.57 ($6.95 third quarter) per MCF for natural gas.

Although the Trust received higher net commodity prices in 2006 than in 2005, increases in the price of U.S. WTI oil prices and U.S. Nymex natural gas prices were partially offset by the rising Canadian dollar. The negative impact of the rising Canadian dollar on 2006's funds flow from operations was approximately 29 cents per unit and approximately 27 cents per unit on net earnings.

Gross revenue has been reduced by $62,000 (2005 - $4,054,000) due to lower prices received as a result of price hedging. The Trust will continue to hedge future production (see Business Prospects, Risks, and Outlooks) to assist in managing its cash flow. The Trust continues to follow the policy of protecting high cost production with hedges that provide a significant level of profitability and also to provide for a reasonable amount of cash flow protection for development projects. The Trust will however maintain a policy of not hedging more than 50 percent of production to allow it to benefit from any price movements in either crude oil or natural gas.

Commodity price hedges outstanding as of the date of this report are as follows:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $74.55 and ceiling of $85.00 per barrel
January 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $95.47 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $93.00 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $70.00 and ceiling of $80.06 per barrel
November 1, 2006 to March 31, 2007	Natural Gas	2,000 GJ's	AECO	Floor of $6.65 and ceiling of $12.50 per GJ
December 1, 2006 to March 31, 2007	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.65 per GJ
April 1, 2007 to July 31, 2007	Natural Gas	2,000 GJ's	AECO	$6.52 per GJ
April 1, 2007 to October 31, 2007	Natural Gas	1,000 GJ's	AECO	Floor of $6.50 and ceiling of $9.20 per GJ
November 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of $6.50 and ceiling of $10.37 per GJ

As of December 31, 2006 the fair value of the outstanding commodity hedging contracts was a net asset of $1,189,000 compared to a net liability of $1,349,000 as of December 31, 2005.

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 2006 the Trust paid $8,517,000 (2005 - $6,986,000) in Crown royalties and $1,996,000 (2005 - $2,009,000) in freehold royalties, gross overriding royalties and net carried interests. The majority of the Trust's wells are low productivity wells and therefore have low Crown royalty rates. The Trust's average Crown royalty rate is approximately ten percent (2005 – nine percent) and approximately two percent (2005 – three percent) for other royalties before hedging adjustments. Crown

royalty rates vary with production volumes and as such the Crown rates are higher on the Trust's newly drilled wells. The Trust was eligible for Alberta Crown Royalty rebates for Alberta production from all wells that it drilled on Crown lands and from a small number of purchased wells. Effective January 1, 2007, the Alberta Government discontinued the rebate.

Gain on Sale of Property

The Trust disposed of its interests in a non-core, non-operated property on January 1, 2006 for proceeds of $750,000 resulting in a gain on sale of $532,000. Production from this property averaged ten barrels per day in 2005. On April 8, 2005, a former subsidiary of Novitas Energy Ltd. ("Novitas") (a subsidiary of the Trust), Pine Cliff Energy Ltd.'s (Pine Cliff) (with common directors and management with Bonterra) rights offering closed with over 97 percent of former Novitas shareholders exercising their rights to acquire common shares in Pine Cliff for $0.15 per common share. As part of the rights offering, the Trust agreed to sell to Pine Cliff effective January 1, 2005 (closing April 9, 2005) approximately 18 BOE per day of production and some exploration lands formally held by Novitas for proceeds of approximately $1,000,000. As a result of this sale the Trust reported a gain on sale of property of $225,000. The balance of the 2005 gain of $38,000 relates to a disposition of an interest in another non-core area property.

Production Costs

Production costs totalled $22,238,000 in 2006 compared to $20,203,000 in 2005. On a barrel of oil equivalent (BOE) basis 2006 operating costs were $15.07 compared to $15.14 for 2005. BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation. Operating costs on the Trust's newly drilled wells are significantly lower on a BOE basis than on its older low productivity wells and has resulted in the Trust being able to maintain its operating costs to BOE rate even though the oil and gas industry saw double digit rates of inflation on its well service costs.

Operating costs were $5,997,000 in the fourth quarter of 2006 compared to $5,689,000 in the third quarter. The increase was due primarily to a $241,000 charge related to an unsuccessful insurance claim relating to a 2005 oil spill.

As discussed above, the Trust's production comes primarily from low productivity wells. These wells generally result in higher operating costs on a per unit-of-production basis as costs such as municipal taxes, surface leases, power and personnel costs are not variable with production volumes. The Trust is continually examining means of reducing operating costs. Operating costs in the $14 to $15 per BOE range are expected for 2007. The high operating costs for the Trust are substantially offset by low royalty rates of approximately 12 percent, which is much lower than industry average for conventional production and results in high cash net backs on a combined basis despite higher than average operating costs.

General and Administrative Expense

General and administrative expenses were $2,295,000 in 2006 compared to $2,420,000 in 2005. On a BOE basis, general and administrative expenses in 2006 averaged $1.56 compared to $1.81 per BOE in 2005. The Trust is managed internally. In addition, the Trust provides administrative services to Comaplex Minerals Corp. (Comaplex) and Pine Cliff, companies that share common directors and management. Please refer to discussion under Related Party Transactions for details.

The Trust's only significant general and administrative cost increase was in employee compensation. The Trust has an employee incentive plan equal to three percent of net earnings before taxes. In 2006 net earnings before taxes increased to $36,864,000

from $33,548,000 in 2005 resulting in an additional $100,000 of employee compensation expense. In addition, the Trust added additional staff to assist with its enhanced capital programs. The additional employee compensation has been offset by higher intercompany charges and increased overhead recoveries charged to operations and capital programs.

The fourth quarter general and administrative expenses were $89,000 lower than the third quarter. The decrease was primarily due to the reduction in the Trust's employee bonus amount resulting from the provision of $2,919,000 in dry hole costs.

Interest Expense

Interest expense for the 2006 fiscal year of the Trust was $1,610,000 (2005 - $575,000). The increase was due to increased loan balances resulting from the Trust's 2006 capital program. The Trust incurred $38,348,000 in capital development expenditures in 2006 resulting in an increase of $25,202,000 in outstanding debt.

Interest rate charges during the year on the outstanding debt averaged approximately 5.3 (2005 – 4.7) percent. The Trust maintained an average outstanding debt balance of approximately $31,000,000 (2005 - $12,250,000). Total debt (including negative working capital) as of December 31, 2006 represents approximately 11.5 months of 2006 annual funds flow or 12.3 months based on annualized 2006 fourth quarter funds flow.

The Trust believes that maintaining debt at or less than one year's funds flow (calculated quarterly based on annualized quarterly results) is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its infill oil, shallow gas and natural gas from coals potential without requiring the issuance of trust units. The Trust's December 31, 2006 debt level is slightly higher than this level. A significant decrease in the fourth quarter price of crude oil coupled with the Trust increasing its 2006 capital program, resulted in higher debt levels and lower funds flow for the quarter. A large number of wells drilled in 2006 were not tied in for production until the fourth quarter of 2006 or in 2007 and therefore contributed little or no cash flow to reduce debt.

The Trust's current bank agreements (each of Bonterra Energy Corp, Comstate Resources Ltd. and Novitas have their own) provide for a combined $49,900,000 (January 1, 2007 - $59,900,000) of available credit facility. Bank debt at December 31, 2006 was $45,379,000 (December 31, 2005 - $20,177,000). The interest rate charged on all non Banker Acceptances (BA's) facility borrowings is bank prime. The Trust's banking arrangements allow it to use BA's as part of its loan facility. Interest charges on BA's are generally one half percent lower than that charged on the general loan account.

Unit Based Compensation

The Trust is required to record a compensation expense over the vesting period of its unit options based on the fair value of the unit options granted to employees, directors and consultants. During the year 447,000 (2005 – 407,000) unit options were granted with a fair value of $2.67 per unit (2005 - $2.49). The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 4.1 (2005 – 3.5) percent, expected weighted average volatility of 27 (2005 – 31) percent, expected weighted average life of 2.5 (2005 – 2.5) years and an annual dividend rate based on the distributions paid to the Unitholders during the year. The result of applying the above, a total unit based compensation of $734,000, based on currently issued and outstanding options, is required to be recorded over the years 2007 and 2008.

Depletion, Depreciation, Accretion and Dry Hole Costs

The Trust follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result

in the addition of reserves, the Trust depletes its oil and natural gas intangible assets using the unit-of-production basis by field. The Trust believes that the successful efforts method of accounting provides a more accurate cost of the producing properties than the alternative measure of full cost accounting.

For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one tenth of original cost per year. The use of a ten year life span instead of calculating depreciation over the life of reserves was determined to be more representative of actual costs of tangible property. Given the Trust's long production life, wells generally require replacement of tangible assets more than once during their life time. Most of the Trust's wells have been producing since the 1960's and are expected to continue to produce for at least another twenty years.

Provisions are made for asset retirement obligations through the recognition of the fair value of obligations associated with the retirement of tangible long-life assets being recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

At December 31, 2006, the estimated total undiscounted amount required to settle the asset retirement obligations was $46,434,000 (2005 - $39,921,000). Of the $6,513,000 increase, approximately $2 million is due to the increased number of wells resulting from the Trust's 2006 capital program, with the balance resulting from increased inflation assumptions.

These obligations will be settled based on the useful lives of the underlying assets, which extend up to 40 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of five percent. The discount rate is reviewed annually and adjusted if considered necessary. A change in the rate would have a significant impact on the amount recorded for asset retirement obligations. Based on the current provision, a one percent increase in the risk adjusted rate would decrease the asset retirement obligation by $2,263,000. While a one percent decrease in the risk adjusted rate would increase the asset retirement obligation by $2,989,000.

The above calculation requires an estimation of the amount of the Trust's petroleum reserves by field. This figure is calculated annually by an independent engineering firm and is used to calculate depletion. This calculation is to a large extent subjective. Reserve adjustments are affected by economic assumptions as well as estimates of petroleum products in place and methods of recovering those reserves. To the extent reserves are increased or decreased, depletion costs will vary.

For the fiscal year ending December 31, 2006, the Trust expensed $15,393,000 (2005 - $10,358,000) for the above-described items including $2,919,000 (2005 - $628,000) for dry hole costs. The increase of $2,744,000 (excluding dry hole costs) over the 2005 balance is due primarily to increased 2006 production levels. The Trust has experienced increased finding and development costs over the past two years (see Finding and Development Costs below). This has resulted in a higher depletion per barrel as production from the 2005/2006 wells make up a larger component of overall production. Based on year end reserves, the Trusts average cost of proved reserves is $5.95 (2005 - $5.08) per BOE.

The dry hole cost of $2,919,000 relates to seven shallow gas wells that were drilled in the winter and summer of 2006. Five of these wells were drilled pursuant to a farm-in agreement where Bonterra was committed to drilling and completing a certain number of wells in order to earn in on the entire land area. In total 12 wells (nine by the end of August) were drilled and completed on the farm in lands in 2006. A further two were drilled in January 2007 to complete the required wells per the farm-in agreements. The wells were designed to test the productivity of the Edmonton Sands shallow gas potential in two separate townships.

The Trust currently has an estimated reserve life for its proved developed producing reserves of 11.0 (2005 – 12.1) years calculated using the Trust's gross reserves (prior to allowance for royalties) based on the third party engineering report dated December 31, 2006 and using fourth quarter 2006 average production rates of 4,119 BOE's (2005 – 3,780 BOE's). Based on total proved reserves the Trust has a 13.6 (2005 – 13.8) year reserve life and if proved and probable are used the reserve life increases to 17.6 (2005 – 17.3) years. These figures are some of the longest (excluding oil sands) reserve life indexes in the Trust sector.

Income Taxes

Taxable income earned within the Trust is required to be allocated to its Unitholders and as such the Trust will not incur any current taxes. Please see discussion under Taxation of Trusts for discussion relating to the newly announced taxation of trusts. However, the Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. (Bonterra Corp.), Comstate Resources Ltd. (Comstate Ltd.) and Novitas. Effective January 1, 2007 the Trust amalgamated Comstate Ltd. and Bonterra Corp. All operating companies pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. For the taxation periods ending prior to 2004 Bonterra Corp. and Comstate Ltd. both paid to the Trust sufficient royalty and interest payments to eliminate all their taxable income. During 2004, due to timing of capital expenditures and other funds flow factors, Comstate Ltd. was unable to pay sufficient payments to the Trust to eliminate all of its taxable income and paid taxes of approximately $560,000. Comstate Ltd. was able to obtain a full refund of the 2004 taxes in 2005.

The Province of Saskatchewan levies a resource surcharge on all oil and gas produced in the province. This surcharge applies if an individual company exceeds a minimum capital threshold or where there are related companies a combined asset threshold also applies. Both Bonterra Corp. and Comstate Ltd. both exceeded the individual company threshold in 2006 and are now subject to the surcharge. The Trust recorded a tax expense of $367,000 in relation to the surcharge. Novitas may be subject to the surcharge by 2007 due to the continued combined growth of the Trust's subsidiaries. Based on the Trust's 2006 revenues, from oil and gas production in the Province of Saskatchewan, and if all operating companies had exceeded the combined asset threshold a total tax expense of $617,000 would have been recorded.

Future tax provision relates to the future taxes that exist within Bonterra Corp., Comstate Ltd. and Novitas. The liability on the balance sheet and the corresponding income tax provision (recovery) relates to temporary differences existing between Bonterra Corp's., Comstate Ltd.'s and Novitas' book value of its assets and its remaining tax pools. Provision for future tax fluctuates quarter over quarter depending on the timing of capital expenditures and funds flow levels in each respective operating company.

The Trust's subsidiaries as of December 31, 2006, have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	**Amount**
Undepreciated capital costs	20-100	$ 15,037,000
Canadian oil and gas property expenditures	10	1,244,000
Canadian development expenditures	30	30,581,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward [1]	100	9,035,000
		$55,990,000

[1] Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000) and 2016 ($4,826,000).

The Trust, as of December 31, 2006, has the following tax pools, which may be used in reducing future taxable income allocated to its Unitholders:

	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	$ 15,685,000
Finance costs	20	626,000
Eligible capital expenditures	7	168,000
		$16,479,000

The Canadian tax breakdown of distributions for the 2006 taxation year is as follows:

	Percentage
Taxable Income (Other Income)	78.80
Return of Capital	21.20
	100.00

With respect to cash distributions paid during the year to U.S. individual unitholders, 18.1 percent should be reported as a return of capital (to the extent of the Unitholder's U.S. tax basis in their respective units) and 81.9 percent should be reported as qualified dividends.

Net Earnings

The Trust's net earnings of $37,250,000 for the year ended December 31, 2006 represents an increase of $3,782,000 over the Trusts 2005 net earnings of $33,468,000. The Trust recorded net earnings per unit on a fully diluted bases in 2006 of $2.21 verses $2.01 in the 2005 year. This represents a return on Unitholders' equity of approximately 69.8 (2005 – 58.4) percent based on year end Unitholders' equity.

Strong commodity prices along with a 10.5 percent increase in production volumes were the main drivers of the increase earnings. The Trust continues to return in excess of 40 percent of its gross revenues in net earnings. The Trust's low capital costs combined with a low debt to funds flow ratio all contribute to the high return. Bonterra's high per unit operating costs are more than offset with its low royalty rates resulting in one of the highest cash net backs in the industry (see cash netback).

Distributable Cash

The computation and disclosures of Distributable Cash in this MD&A is in all material respects, except that only fiscal year 2006, 2005 and 2004 information is provided, with the guidance provided in CICA's publication "Distributable Cash in Income Trusts and Other Flow-Through Entities – Guidance on Preparation and Disclosure in Management's Discussion and Analysis – An Interpretive Release."

For the years ended December 31	2006	2005	2004
Cash Flow from Operating Activities	**$51,944,000**	$38,985,000	$29,817,000
Less Adjustment for:			
Productive Capacity Maintenance (1)	**(17,472,000)**	(9,205,000)	(3,460,000)
Long Term Unfunded Contractual Operational Obligations (2)	**(308,000)**	(648,000)	(533,000)
Financing Restrictions Caused by Debt (3)	**–**	–	–
Distributable Cash from Operations	**$34,164,000**	$29,132,000	$25,824,000
Cash generated from the gain on sale of properties	**532,000**	263,000	–
Cash generated from increase in debt	**12,173,000**	8,606,000	197,000
Working capital adjustments	**412,000**	948,000	1,067,000
Unit Distributions	**$47,281,000**	$38,949,000	$27,088,000

(1) Bonterra's primary objective is to grow its reserves from which it generates enhanced distributions for its unitholders. The Trust defines Productive Capacity Maintenance as the maintaining of the Trusts proven plus probable reserves. The Trust follows a policy of internal development as its primary method of planned growth. Bonterra has a significant inventory of undrilled Cardium oil infill drilling locations as well as several shallow gas opportunities on its lands or through farm-in agreements. Please refer to our property discussion for more details. It is management's view that the calculation of the amount required for Productive Capacity Maintenance is the amount of reserves produced in the relevant time period multiplied by the Trust's finding and development costs for proven plus probable reserves. For this purpose the Trust believes that the use of a three year average rate is reasonable given fluctuations in annual costs due to market conditions.

(2) Long Term Unfunded Contractual Operational Obligations in the case of the Trust includes only its Asset Retirement Obligations. For this purpose the Trust calculates this adjustment as the period accretion charge plus the period depletion charge of the asset retirement obligation fixed asset adjustment less actual asset retirement expenditures incurred in the period.

(3) The Trust has no financing restrictions. Please see discussions under Interest Expense and Liquidity and Capital Resources.

The payout ratio as calculated using distributable cash from operations is 138 percent in 2006, 134 percent in 2005 and 105 percent in 2004. Over the past two years the Trust has incurred significant costs related to its development programs. In addition, the Trust had minimal tax pools available at the corporate level to shelter taxable income that would be generated by retaining sufficient operating cash flow to cover the productive capacity maintenance capital requirements.

The Trust's relatively low debt level, which most of the time over the past two years was less than 6 months to cash flow, allowed management to consciously decide to maintain a high level of distributions. On a go forward basis the Trust plans to reduce the payout ratio in respect of distributable cash to a level between 110 to 120 percent to facilitate a debt to cash flow level of approximately one year and to incur no current income tax (excluding Saskatchewan Resource Surcharge). Capital expenditures in excess of those required for Productive Capital Maintenance will be funded through additional unit issuances which include employee unit option exercises.

Funds Flow from Operations

Funds flow from operations for the year ending December 31, 2006 was $52,797,000 compared to $44,579,000 for the year ended December 31, 2005. Funds flow from operations is not a recognized measure under GAAP. The Trust believes that in addition to net earnings, funds flow from operations is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors

are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines funds flow from operations as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement expenditures.

The increase was primarily due to higher commodity prices and higher production volumes. As with all oil and gas producers the Trust's funds flow is highly dependent on commodity prices. International events and control of crude oil production by OPEC are likely factors that will result in 2007 commodity prices being high and having a positive impact on funds flow.

The following reconciliation compares funds flow to the Trust's cash flow from operations as calculated according to Canadian generally accepted accounting principles:

	Three Months		Twelve Months	
For the periods ended December 31	**2006**	2005	**2006**	2005
Cash flow from operations for the period	**$11,925,000**	$12,342,000	**$51,944,000**	$38,985,000
Items not affecting funds flow:				
Gain on sale of property	**–**	–	**532,000**	263,000
Changes in accounts receivable	**1,102,000**	50,000	**147,000**	2,814,000
Changes in crude oil inventory	**(179,000)**	66,000	**7,000**	134,000
Changes in parts inventory	**5,000**	(3,000)	**(107,000)**	(170,000)
Changes in prepaid expenses	**(299,000)**	(380,000)	**305,000**	(306,000)
Changes in accounts payable and accrued liabilities	**(688,000)**	369,000	**(793,000)**	2,584,000
Asset retirement obligations settled	**369,000**	45,000	**762,000**	275,000
Funds flow from operations for the period	**$12,235,000**	$12,489,000	**$52,797,000**	$44,579,000

Cash Netback

The following table illustrates the Trust's cash netback:

$ per Barrel of Oil Equivalent (BOE)	**2006**	2005
Production volumes (BOE)	**1,475,639**	1,334,075
Gross production revenue	**60.13**	56.85
Royalties	**(7.12)**	(6.74)
Field operating	**(15.07)**	(15.14)
Field netback	**37.94**	34.97
General and administrative	**(1.56)**	(1.81)
Interest and taxes	**(1.34)**	(0.30)
Cash netback	**35.04**	32.86

The following table illustrates the Trust's cash netback for the three months ended:

$ per Barrel of Oil Equivalent (BOE)	December 31, 2006	September 30, 2006
Production volumes (BOE)	378,916	369,104
Gross production revenue	57.32	64.12
Royalties	(6.37)	(6.77)
Field operating	(15.83)	(15.41)
Field netback	35.12	41.94
General and administrative	(1.27)	(1.55)
Interest and taxes	(1.64)	(1.38)
Cash netback	32.21	39.01

Finding and Development Costs (F&D Costs)

Bonterra has been active in its capital development program over the past three years. Over this time period the Trust has incurred the following finding and development costs:

	2006 F&D Costs per BOE (1)(2)	2005 F&D Costs per BOE (1)(2)	2004 F&D Costs per BOE (1)(2)	2006 Three Year Average	2005 Three Year Average
Proved Reserve Additions	$25.51	$14.86	$7.33	$15.90	$10.47
Proved plus Probable Reserve Additions	$18.21	$12.33	$4.97	$11.84	$6.90

The above figures have been calculated in accordance with National Instrument 51-101 (NI 51-101) where the finding and development costs equate to the total exploration and development costs incurred by the Trust during the year plus the yearly change in estimated future development costs as calculated by Sproule Associates Limited. The following precautionary notes have been provided as required by NI 51-101.

(1) BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6MCF:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Escalating development costs combined with moderate results in the Trusts shallow gas drilling program in 2006 has resulted in a substantial increase in 2006 F&D costs. With the recent reduction in commodity prices, the Trust is being able to negotiate lower drilling rig costs in respect of its 2007 winter drill program.

Related Party Transactions

The Trust holds 689,682 (2005 – 689,682) common shares in Comaplex which have a fair market value as of December 31, 2006 of $2,297,000 (2005 - $2,448,000). Comaplex is a publically traded mineral company on the Toronto Stock Exchange. The Trust's ownership in Comaplex represents approximately 1.7 percent of the issued and outstanding common shares of Comaplex. Bonterra has common directors and management with Comaplex.

Comaplex paid a management fee to Comstate Ltd. of $300,000 (2005 - $240,000). Comaplex also cost shares office rental costs and reimburses Comstate Ltd. for costs related to employee benefits and office materials. In addition Comaplex owns 204,633 (December 31, 2005 – 204,633) units in the Trust. Services provided by Comstate Ltd. include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. At December 31, 2006, Comaplex owed the Trust $38,000 (December 31, 2005 - $29,000).

The Trust also has a management agreement with Pine Cliff. Pine Cliff has common directors and management with the Trust. Pine Cliff trades on the TSX Venture Exchange. Pine Cliff paid a management fee to Comstate Ltd. of $216,000 (2005 - $132,000). Services provided by Comstate Ltd. include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. The Trust has no share ownership in Pine Cliff. There were no intercompany balances owing as of December 31, 2006.

Commitments

The Trust has no contractual obligations that last more than a year other than its office lease agreement which is as follows:

Contract Obligations	**Total**	**Less than 1 year**	**1 – 3 years**	**4 – 5 years**	**After 5 years**
Office Lease	$1,963,000	$283,000	$910,000	$656,000	$114,000

Changes in Accounting Policies

The Canadian Accounting Standards Board has issued new accounting standards for financial instruments that comprehensively address when an entity should recognize a financial instrument on its balance sheet, or how it should measure the financial instrument once recognized. The new standards comprise three handbook sections:

- CICA Section 3855 – Financial Instruments – Recognition and Measurement establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It also specifies how financial instrument gain and losses are to be presented.
- CICA Section 3865 – Hedges provides optional alternative treatments to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It will replace Accounting Guideline 13 (AcG – 13), Hedging Relationships, and build on Section 1650, Foreign Currency Translation, by specifying how hedge accounting is applied and what disclosures are necessary when it is applied.
- CICA Section 1530 – Comprehensive Income introduces a new requirement to temporarily present certain gains and losses as part of a new earnings measurement called comprehensive income.

All three standards are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust plans on implementing them effective January 1, 2007.

The impact of the new standards to the Trust is moderate. The Trust will be recording on its balance sheet its investment in Comaplex at its fair value, which was $2,297,000 as of December 31, 2006. The investment will be adjusted each quarter to reflect changes in their market value. These adjustments along with the initial fair value adjustment will be recorded in the new statement of comprehensive income. The unrealized gains or losses will be transferred to net earnings when the investment is disposed of.

The Company also plans to use hedge accounting to the extent possible for its future commodity price contracts. The impact is to record any asset or liability pertaining to the hedges on the Trust's balance sheet and record fair value adjustments in these contracts through comprehensive income until the contracts expire. The immediate impact is to record an asset of $1,189,000 as of December 31, 2006. The adjustments along with the initial fair value adjustment will be recorded in the new statement of comprehensive income.

Liquidity and Capital Resources

During 2006 the Trust participated in drilling 61 gross (45.6 net) wells at a total cost of $38,348,000. Of these wells, 43 gross (30.3 net) were oil wells and 18 gross (15.3 net) were natural gas wells. The Trust's operated 2006 drill program consisted of 34 gross (29 net) Cardium oil wells and 17 gross (14.7 net) natural gas wells.

As at December 31, 2006 Bonterra had 21 gross (11.4 net) Cardium oil wells (including 9 gross, 1.3 net on non operated lands), 12 gross (9.3 net) natural gas wells and 7 gross (5.5 net) coal-bed wells drilled but not on production. Subsequent to December 31, 2006 and up to the date of this report, Bonterra has put on production 6 gross (5.8 net) Cardium oil wells and 2 gross (1 net) shallow gas wells. The Trust is currently completing several of its Edmonton sand gas wells drilled in 2006 and anticipates that the majority of the gas wells will be on production by the end of the second quarter of 2007. Bonterra is waiting on final regulatory decisions and recovery in natural gas pricing prior to commencing further completion work on the coal-bed methane wells.

The Trust currently has plans to drill 20 gross (15 net) infill Cardium wells and 2 gross (1.8 net) natural gas wells in 2007. Total capital costs are anticipated to be approximately $20,000,000 for the planned development programs and tying in of the remaining 2006 drilled wells. The Trust anticipates funding the 2007 capital program out of current funds flow ($10-$15 million), exercising of employee unit options ($2-$3 million) and existing lines of credit. This combination should allow for the Trust to maintain an approximate one year debt to funds flow ratio.

The Trust is continuing with its efforts to acquire producing and non producing properties through either property or entity acquisitions. Funding for any acquisition would depend on items such as the type of acquisition (entity vs. property), quality of the assets, size of the purchase and the Trust unit trading price at the time of the acquisition.

At December 31, 2006 the Trust had bank debt of $45,379,000 (2005 – $20,177,000). The Trust through its operating subsidiaries has bank revolving credit facilities totalling $49,900,000 at December 31, 2006 (December 31, 2005 - $36,900,000). Effective January 1, 2007 this amount has been increased to $59,900,000. The facilities carry an interest rate of Canadian chartered bank prime.

The terms of the credit facilities provide that the loans are due on demand and are subject to annual review. The credit facilities have no fixed payment requirements. The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit of $340,000 at December 31, 2006 and 2005. Security for the credit facility consists of various fixed and floating demand debentures totalling $79,000,000 over all of the Trust's assets, and a general security agreement with first ranking over all personal and real property. As the Trust maintains a low debt to funds flow ratio and also has a substantial asset value (see review of operations), the Trust's banker does not require any financial statement ratio or other debt covenants other than those described above.

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. The following table outlines changes in the Trust's unit structure over the past two years.

Issued	2006 Number	2006 Amount	2005 Number	2005 Amount
Trust Units				
Balance, beginning of year	**16,535,158**	**$83,900,000**	14,943,405	$75,486,000
Transfer of contributed surplus to Unit capital	**–**	**427,000**	–	169,000
Units issued on acquisition of Novitas	**–**	**–**	1,335,753	5,681,000
Unit issue costs on acquisition of Novitas	**–**	**–**	–	(259,000)
Issued pursuant to Trust unit option plan	**339,500**	**5,161,000**	256,000	2,823,000
Balance, end of year	**16,874,658**	**$89,488,000**	16,535,158	$83,900,000

In 2005, the Trust issued 1,335,753 units at a value of $25 per unit plus paid $769,000 in cash for all of the issued and outstanding common shares of Novitas. For accounting purposes the transaction was recorded at the cost of the Novitas' assets and liabilities due to Novitas being considered a related party to the Trust.

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,670,000 (2005 – 1,635,000) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years.

A summary of the status of the Trust's unit option plan as of December 31, 2006 and 2005, and changes during the years ending on those dates is presented below:

	2006 Options	2006 Weighted-Average Exercise Price	2005 Options	2005 Weighted-Average Exercise Price
Outstanding at beginning of year	**646,000**	**$18.67**	565,000	$11.56
Options granted	**447,000**	**29.18**	407,000	23.32
Options exercised	**(339,500)**	**15.20**	(256,000)	11.03
Options cancelled	**(32,000)**	**24.70**	(70,000)	16.35
Outstanding at end of year	**721,500**	**$26.55**	646,000	$18.67
Options exercisable at end of year	**212,500**	**$22.62**	214,000	$10.89

The following table summarizes information about unit options outstanding at December 31, 2006:

Range of Exercise Prices	Options Outstanding: Number Outstanding At 12/31/06	Options Outstanding: Weighted-Average Remaining Contractual Life	Options Outstanding: Weighted-Average Exercise Price	Options Exercisable: Number Exercisable At 12/31/06	Options Exercisable: Weighted-Average Exercise Price
$15.20	31,000	0.5 years	$ 15.20	19,000	$15.20
$22.45-$23.35	251,000	2.3 years	23.32	193,500	23.35
$28.70-$28.75	399,000	2.2 years	28.75	–	–
$32.00-$33.75	40,000	3.0 years	33.55	–	–
$15.20-$33.75	721,500	2.1 years	$26.55	212,500	$22.62

Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations. Please see following section on the Canadian Governments tax announcement.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Trust's funds flow or in the value of its producing and non-producing oil and natural gas properties.

The Trust presently attempts to minimize these risks by pursuing both oil and natural gas activities and operates its oil and natural gas interests in areas which have long life reserves, where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

The Trust also maintains an active hedging program. Currently the Trust has forward sales agreements in place for approximately 32 percent of its estimated 2007 production on a BOE basis. The Trust uses a combination of fixed price swaps as well as no cost collars to protect against commodity price declines.

Taxation of Trusts

On October 31, 2006 the Minster of Finance for Canada announced new proposals for the taxation of existing income trusts. In summary under the new proposals:

- An income trust will be subject to a special rate of tax on its distributions of income that is attributable to income from business carried on in Canada, income from non-portfolio investments in Canadian resource properties, and capital gains from the above.
- Distributions from income trusts will be taxed in the same manner as a dividend from a taxable Canadian corporation.
- For existing trusts the new rules apply to taxation years that end after 2010.
- The tax rate that would apply to taxation years after 2010 would be 31.5 percent.

In addition the Minister announced the governments attempt to limit the growth of existing income trusts. Under the proposals, the government will not recommend any change to the 2011 date in respect of any income trust whose equity capital grows as a result of issuances of new equity, in any of the years from now to 2011 by an amount that does not exceed the greater of $50 million and an objective "safe harbour" amount. The safe harbour amount will be measured by reference to the trusts market capitalization as of the end of trading on October 31, 2006. Market capitalization is to be measured in terms of the value of an income trusts issued and outstanding publicly-traded units. For the period November 1, 2006 to December 31, 2007 an income trusts safe harbour will be 40 percent of that October benchmark and 20 percent for each calendar year 2008, 2009 and 2010.

The Minister also announced the government's intent to allow for conversions of income trusts back to corporate form as well as to allow the mergers of income trusts without effecting the above safe harbour amounts.

The above proposals have not been made law as of the date of this report. In addition, the rules surrounding the safe harbour rules and conversion to a corporate form have not yet been drafted into legislation.

The impact to individual unitholders of the above proposals differs by the category of the investor. For Canadian individual or Canadian taxable corporation investors the distributions will be subject to the dividend tax credit which should offset to a large degree the tax paid by the Trust. For those investors that hold their trust units in a tax deferred fund (RRSP's, RRIF's or in a pension fund) there will be double taxation of distributions. This will result in an effective rate of tax in most cases in excess of 55 percent. Thirty one point five percent at the trust level and a further tax on withdrawal from the fund based on the individual's tax rate. Also for non-resident investors there will be a significant double taxation as well. The trust again pays its 31.5 percent, then a further 15 percent withholding is required and the non-residents must also pay their own federal and state taxes. This could result in excess of 60 percent being paid in taxes.

Bonterra's market value has been significantly impacted by the above announcement. The Trust traded at $37.50 on October 31, 2006, and ended the year at $25.57. The actual impact on operations to date has been minimal. However, the uncertainty of how the legislation will be drafted and eventually put into law has caused the Trust to be more conservative when examining its current operations.

As of January 2, 2007, the Trust is believed to be owned approximately 25 percent by non-residents (based on ADP Canada and ADP USA beneficial reports). As for the ownership by tax deferred funds, it is managements estimate that no more than 15 percent is held by such entities. Therefore the majority of the beneficial owners of Bonterra are estimated to be taxable Canadian investors.

Management has been examining its options. These include:

(1) Continuing as a trust.
(2) Continuing as a trust to 2011 and converting to a corporation at that time.
(3) Immediate conversion to a corporation.

All of these options have differing impacts to the Trust's various unitholders. With the fact the current government is in a minority position in the house of commons, there is a large degree of uncertainty as to whether the draft legislation will be passed, what amendments if any would be made, what further legislation will be enacted to cover the safe harbour rules and conversion features as well as a possible delay in the implementation of the tax. All of these considerations may very will impact management's decision regarding the best course of action for Bonterra.

Until more concrete information can be obtained it is management's position that the Trust should continue with its current operations. The proposed safe harbour rules will allow the Trust to raise in excess of $650,000,000 over the next four years without losing its tax free status to 2011. This will allow the trust to continue with its Cardium infill drilling program, its shallow natural gas and natural gas from coals development as well as potentially developing a CO_2 flood program. Emphasis will be placed on increasing the Trusts available tax pools to assist in mitigating any future tax consequences should the legislation be passed.

Management will ensure that as information about the taxation of trusts is provided all such relevant information will be made available to Unitholders through press releases or as part of the Trust's continuous disclosure requirements.

Sensitivity Analysis

Sensitivity analysis, as estimated for 2007:

	Cash Flow	Cash Flow Per Unit
U.S. $1.00 per barrel	$ 762,000	$0.045
Canadian $0.10 per MCF	$ 459,000	$0.027
Change of Canadian $0.01/U.S. $ exchange rate	$ 502,000	$0.030

Additional Information

Additional information relating to the Trust may be found on SEDAR.COM as well as on the Trust's web-site at www.bonterraenergy.com.

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of the statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte & Touche LLP has been appointed by the Unitholders to serve as the Trust's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink

President and CEO

Garth E. Schultz

Vice President, Finance and CFO

Auditors' Report

To the Unitholders of Bonterra Energy Income Trust:

We have audited the consolidated balance sheets of Bonterra Energy Income Trust as at December 31, 2006 and 2005 and the consolidated statements of Unitholders' equity, operations and deficit, and cash flow for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta

March 13, 2007

Bonterra Energy Income Trust

Consolidated Balance Sheets

As at December 31	2006	2005
Assets		
Current		
Accounts receivable (Note 8)	**$ 10,486,000**	$ 11,020,000
Crude oil inventory	**843,000**	836,000
Parts inventory	**114,000**	221,000
Prepaid expenses	**1,086,000**	781,000
Investment in related party (Note 2)	**461,000**	461,000
	12,990,000	13,319,000
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	**176,602,000**	139,798,000
Accumulated depletion and depreciation	**(54,650,000)**	(42,968,000)
	121,952,000	96,830,000
	$134,942,000	$110,149,000
Liabilities		
Current		
Distribution payable	**$ 4,050,000**	$ 3,638,000
Accounts payable and accrued liabilities	**13,748,000**	11,476,000
Debt (Note 4)	**45,379,000**	20,177,000
	63,177,000	35,291,000
Future income tax liability (Note 5)	**3,587,000**	4,341,000
Asset retirement obligations (Note 6)	**14,819,000**	13,195,000
	81,583,000	52,827,000
Commitments, Contingencies and Guarantees (Note 10)		
Unitholders' Equity (Note 7)		
Unit capital	**89,488,000**	83,900,000
Contributed surplus	**1,116,000**	636,000
Deficit	**(37,245,000)**	(27,214,000)
	53,359,000	57,322,000
	$134,942,000	$110,149,000

On behalf of the Board:

Director

Director

Bonterra Energy Income Trust

Consolidated Statements of Unitholders' Equity

For the Years Ended December 31	2006	2005
Unitholders equity, beginning of year	**$ 57,322,000**	$ 54,060,000
Net earnings for the year	**37,250,000**	33,468,000
Net capital contributions (Note 7)	**5,161,000**	2,823,000
Units issued on acquisition of Novitas Energy Ltd. (Note 7)	**–**	5,681,000
Unit issue costs on acquisition of Novitas Energy Ltd. (Note 7)	**–**	(259,000)
Unit based compensation adjustment	**907,000**	498,000
Distributions declared	**(47,281,000)**	(38,949,000)
Unitholders' Equity, End of Year	**$ 53,359,000**	$57,322,000

rra Energy Income Trust

Consolidated Statements of Operations and Deficit

For the Years Ended December 31	2006	2005
Revenue		
Oil and gas sales	**$ 88,734,000**	$ 75,837,000
Royalties	**(10,512,000)**	(8,995,000)
Alberta royalty tax credits	**487,000**	464,000
Gain on sale of property (Note 3)	**532,000**	263,000
Interest and other	**66,000**	33,000
	79,307,000	67,602,000
Expenses		
Production costs	**22,238,000**	20,203,000
General and administrative	**2,295,000**	2,420,000
Interest on debt	**1,610,000**	575,000
Unit based compensation	**907,000**	498,000
Dry hole costs	**2,919,000**	628,000
Depletion, depreciation and accretion	**12,474,000**	9,730,000
	42,443,000	34,054,000
Earnings Before Income Taxes	**36,864,000**	33,548,000
Income taxes (recovery) (Note 5)		
Current	**367,000**	(175,000)
Future	**(753,000)**	255,000
	(386,000)	80,000
Net Earnings for the Year	**37,250,000**	33,468,000
Deficit, beginning of year	**(27,214,000)**	(21,733,000)
Distributions declared	**(47,281,000)**	(38,949,000)
Deficit, end of year	**$ (37,245,000)**	$(27,214,000)
Net Earnings Per Unit – Basic (Note 7)	**$ 2.23**	$ 2.04
Net Earnings Per Unit – Diluted (Note 7)	**$ 2.21**	$ 2.01

Bonterra Energy Income Trust

Consolidated Statements of Cash Flow

For the Years Ended December 31	2006	2005
Operating Activities		
Net earnings for the year	**$ 37,250,000**	$33,468,000
Items not affecting cash		
Gain on sale of property	**(532,000)**	(263,000)
Unit based compensation	**907,000**	498,000
Dry hole costs	**2,919,000**	628,000
Depletion, depreciation and accretion	**12,474,000**	9,730,000
Future income taxes (recovery)	**(753,000)**	255,000
	52,265,000	44,316,000
Change in non-cash working capital		
Accounts receivable	**(147,000)**	(2,814,000)
Crude oil inventory	**(7,000)**	(134,000)
Parts inventory	**107,000**	170,000
Prepaid expenses	**(305,000)**	306,000
Accounts payable and accrued liabilities	**793,000**	(2,584,000)
Asset retirement obligations settled	**(762,000)**	(275,000)
	(321,000)	(5,331,000)
	51,944,000	38,985,000
Financing Activities		
Increase in debt	**25,202,000**	11,717,000
Unit option proceeds	**5,161,000**	2,823,000
Unit issue costs on acquisition of Novitas Energy Ltd.	**–**	(259,000)
Unit distributions	**(46,869,000)**	(38,001,000)
	(16,506,000)	(23,720,000)
Investing Activities		
Property and equipment expenditures	**(38,348,000)**	(16,669,000)
Proceeds on sale of property	**750,000**	1,097,000
Abandonment deposit	**–**	1,522,000
Cash portion of Novitas Energy Ltd. acquisition	**–**	(769,000)
	(37,598,000)	(14,819,000)
Change in non-cash working capital		
Accounts receivable	**681,000**	(534,000)
Accounts payable and accrued liabilities	**1,479,000**	88,000
	2,160,000	(446,000)
	(35,438,000)	(15,265,000)
Net cash inflow	**–**	–
Cash, beginning of year	**–**	–
Cash, end of year	**$ –**	$ –
Cash interest paid	**$ 1,610,000**	$ 575,000
Cash taxes paid	**$ 393,000**	$ 894,000

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described below.

Consolidation

These consolidated financial statements include the accounts of Bonterra Energy Income Trust (the "Trust") and its wholly owned subsidiaries Bonterra Energy Corp. (Bonterra), Comstate Resources Ltd. (Comstate) and effective January 7, 2005, Novitas Energy Ltd. (Novitas). Effective January 1, 2007, Bonterra and Comstate amalgamated. Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used in ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the financial statements of future periods.

Inventories

Inventories consist of crude oil as well as materials and supplies which include tubing, rods, motors, pump jacks, bases and miscellaneous parts used in the maintenance of the Trust's tangible equipment. Both crude oil and materials and supplies are valued at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, royalties and depletion and depreciation for the year and net realizable value is determined based on sales price in the month preceding year end.

Investments

Investments are carried at the lower of cost and market value.

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Trust follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs including geological and geophysical costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Producing properties and significant unproved properties are assessed annually or more frequently as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method. Development and exploration drilling and equipment costs are depleted over the remaining proved developed reserves. Depreciation of other plant and equipment is provided on the straight line method. Straight line depreciation is based on the estimated service lives of the related assets which is estimated to be ten years.

Furniture, Fixtures and Office Equipment

These assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

Income Taxes

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported for assets and liabilities by the Trust's subsidiary companies in the consolidated financial statements of the Trust and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust allocates all of its taxable income to the Unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust. However, the Trust's subsidiaries are subject to taxation on income which is not transferred to the Trust.

In the Trust structure, payments are made between the Trust's operating subsidiaries and the Trust which result in the transferring of taxable income from the operating subsidiaries to individual Unitholders. These payments may reduce future income tax liabilities previously recorded by the operating companies which would be recognized as a recovery of income tax in the period incurred.

Asset Retirement Obligations

The fair value of obligations associated with the retirement of long-life assets are recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion

charges which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

Trust Unit-Based Compensation

The Trust has a unit-based compensation plan, which is described in Note 7. The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. These amounts are recorded as contributed surplus. Any consideration paid by employees, directors or consultants on the exercise of these options is recorded as unit capital together with the related contributed surplus associated with the exercised options.

Revenue Recognition

Revenues associated with sales of petroleum and natural gas are recorded when title passes to the customer.

Hedging

Derivative financial instruments are utilized to reduce commodity price risk on the Trust's product sales. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified product sale. The Trust assesses the derivative financial instruments for effectiveness as hedges, both at inception and over the term of the instrument. The production volume in the derivative financial instruments all match the production being hedged.

Commodity price swap agreements are used as part of the Trust's program to manage its product pricing. The commodity price swap agreements involve the periodic exchange of payments and are recorded as adjustments of net revenue. For the twelve months ended December 31, 2006 the Trust recorded a reduction to net revenue of $62,000 (2005 - $4,054,000) with respect to these agreements.

Joint Interest Operations

Significant portions of the Trust's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Trust's proportionate interest in such activities.

Net Earnings Per Unit

Basic earnings per unit are computed by dividing earnings by the weighted average number of units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if options to purchase trust units were exercised. The treasury stock method is used to determine the dilutive effect of trust unit options, whereby proceeds from the exercise of trust unit options or other dilutive instruments are assumed to be used to purchase trust units at the average market price during the period.

3. INVESTMENT IN RELATED PARTY AND ACQUISITION OF NOVITAS ENERGY LTD.

The investment consists of 689,682 (December 31, 2005 – 689,682) common shares in Comaplex Minerals Corp (Comaplex), a company with common directors and management with the Trust and its subsidiaries. The investment is recorded at cost. The fair market value as determined by using the trading price of the stock at December 31, 2006 was $2,297,000 (December 31, 2005 - $2,448,000). The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a two percent ownership in the outstanding shares of Comaplex.

On January 7, 2005 the Trust acquired Novitas. The acquisition was accounted for at Novitas' carrying value due to the related status of Novitas to the Trust. The carried values were as follows:

Accounts receivable	$ 568,000
Crude oil inventory	122,000
Prepaid expenses	47,000
Property and equipment	23,130,000
Accumulated depletion and depreciation	(6,522,000)
Accounts payable and accrued liabilities	(2,010,000)
Debt	(4,598,000)
Future income tax liability	(3,089,000)
Asset retirement obligations	(1,198,000)
	$ 6,450,000

The acquisition cost was $769,000 cash and the issuance of 1,335,753 trust units.

3. PROPERTY AND EQUIPMENT

	2006		2005	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 334,000	$ -	$ 334,000	$ -
Petroleum and natural gas properties and related equipment	175,353,000	54,008,000	138,713,000	42,622,000
Furniture, equipment and other	915,000	642,000	751,000	346,000
	$ 176,602,000	$ 54,650,000	$ 139,798,000	$ 42,968,000

In January 2006 the Trust completed the sale of a non-operated oil and gas property for gross proceeds of $750,000 to an unrelated third party. The disposition resulted in the Trust reporting a gain on sale of $532,000.

On April 8, 2005, a former subsidiary of Novitas, Pine Cliff Energy Ltd. (Pine Cliff) (with common directors and management with the Trust and its subsidiaries) closed a rights offering with over 97 percent of former Novitas shareholders exercising their rights to acquire common shares in Pine Cliff for $0.15 per common share. As part of the rights offering, the Trust agreed to sell to Pine Cliff effective January 1, 2005 (closing April 8, 2005) approximately 18 barrels per day of oil equivalent of production and some exploration lands formerly held by Novitas for proceeds of approximately $1,000,000. As a result of this sale the Trust reported a gain on sale of property of $225,000. The Trust also disposed of minor non-core area properties for proceeds of approximately $97,000 for a gain of $38,000.

4. DEBT

The Trust has a bank revolving credit facility of $49,900,000 at December 31, 2006 (2005 - $36,900,000). Effective January 2, 2007 the revolving credit facility was increased to $59,900,000. The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for

borrowing under the credit facility is reduced by outstanding letters of credit. Letters of credit totalling $340,000 (December 31, 2005 - $340,000) were issued at December 31, 2006. Security for the credit facility consists of various fixed and floating demand debentures totalling $79,000,000 over all of the Trust's assets, and a general security agreement with first ranking over all personal and real property.

The credit facility carries an interest rate of Canadian chartered bank prime. The Trust has classified this debt as a current liability as required by GAAP. It has been management's experience that these types of demand loans which are required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. Cash interest paid during the year ended December 31, 2006 for this loan was $1,610,000 (2005 - $575,000).

5. INCOME TAXES

The Trust has recorded a future income tax liability related to assets and liabilities and related tax amounts held through its 100 percent owned operating subsidiaries. The following figures do not reflect the potential consequences of the Canadian Federal Government's October 31, 2006 announcement on the future taxation of income trusts. The liability relates to the following temporary differences in those subsidiaries:

	2006	2005
Future income tax liability to assets and liabilities of the subsidiary companies	$ 6,233,000	$ 5,919,000
Future tax asset related to finance costs in corporate subsidiaries	-	(12,000)
Future tax asset related to corporate tax losses carried forward in the subsidiary companies	(2,646,000)	(1,566,000)
	$ 3,587,000	$ 4,341,000

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	2006	2005
Earnings before income taxes	$ 36,864,000	$ 33,548,000
Combined federal and provincial income tax rates	34.97%	38.08%
Income tax provision calculated using statutory tax rates	12,891,000	12,775,000
Increase (decrease) in taxes resulting from:		
Saskatchewan resource surcharge	389,000	347,000
Unit-based compensation	317,000	190,000
Non-deductible Crown royalties	1,072,000	1,793,000
Resource allowance	(1,901,000)	(3,283,000)
Trust income allocated to Unitholders	(13,031,000)	(12,763,000)
Adjustment on acquisition of Novitas	-	1,055,000
Others	(123,000)	(34,000)
Income tax expense (recovery)	$ (386,000)	$ 80,000

The Trust's subsidiaries have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$ 15,037,000
Canadian oil and gas property expenditures	10	1,244,000
Canadian development expenditures	30	30,581,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward (1)	100	9,035,000
		$ 55,990,000

(1) Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000) and 2016 ($4,826,000).

The Trust has the following tax pools, which may be used in reducing future taxable income allocated to its Unitholders:

	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	$ 15,685,000
Finance costs	20	626,000
Eligible capital expenditures	7	168,000
		$ 16,479,000

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts. Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The proposals would result in a two-tiered tax structure whereby distributions would first be subject to a 31.5 percent at the Trust level commencing in 2011 and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. If enacted, the proposals would apply to the Trust effective January 1, 2011. The Trust is currently assessing various alternatives with respect to the potential implications of the tax proposals; however, until the legislation is enacted in final form, the Trust will not arrive at a final conclusion with respect to future Trust structure and implications to the Trust. As the tax proposals had not been substantively enacted as of December 31, 2006, the consolidated financial statements do not reflect the impact of the proposed taxation.

6. ASSET RETIREMENT OBLIGATIONS

At December 31, 2006, the estimated total undiscounted amount required to settle the asset retirement obligations was $46,434,000 (2005 - $39,921,000). Costs for asset retirement have been calculated assuming a 5 percent inflation rate for 2007, 4 percent for 2008, 3 percent for 2009 and 2 percent thereafter. These obligations will be settled based on the useful lives of the underlying assets, which extend up to 40 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of 5 (2005 – 5) percent.

Changes to asset retirement obligations were as follows:

	2006	2005
Asset retirement obligations, January 1	$ 13,195,000	$ 11,419,000
Adjustment to asset retirement obligations	1,726,000	233,000
Acquisition of Novitas	-	1,198,000
Liabilities settled during the year	(762,000)	(275,000)
Accretion	660,000	620,000
Asset retirement obligations, December 31	$ 14,819,000	$ 13,195,000

7. UNIT CAPITAL

Authorized

The Trust is authorized to issue an unlimited number of trust units without nominal or par value.

	2006		2005	
Issued	**Number**	**Amount**	**Number**	**Amount**
Trust Units				
Balance, beginning of year	16,535,158	$ 83,900,000	14,943,405	$ 75,486,000
Transfer of contributed surplus to Unit capital	-	427,000	-	169,000
Units issued on acquisition of Novitas	-	-	1,335,753	5,681,000
Unit issue costs on acquisition of Novitas	-	-	-	(259,000)
Issued pursuant to Trust unit option plan	339,500	5,161,000	256,000	2,823,000
Balance, end of year	16,874,658	$ 89,488,000	16,535,158	$ 83,900,000

The number of trust units used to calculate diluted net earnings per unit for the year ended December 31, 2006 of 16,880,422 (2005 – 16,594,260) included the basic weighted average number of units outstanding of 16,737,651 (2005 – 16,388,621) plus 142,771 (2005 – 205,639) units related to the dilutive effect of unit options.

The deficit balance is composed of the following items:

	2006	2005
Accumulated earnings	$ 122,406,000	$ 85,156,000
Accumulated cash distributions	(159,651,000)	(112,370,000)
Deficit	$ (37,245,000)	$ (27,214,000)

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,670,000 (2005 – 1,635,000) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years.

A summary of the status of the Trust's unit option plan as of December 31, 2006 and 2005, and changes during the years is presented below:

	2006		2005	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	646,000	$ 18.67	565,000	$ 11.56
Options granted	447,000	29.18	407,000	23.32
Options exercised	(339,500)	15.20	(256,000)	11.03
Options cancelled	(32,000)	24.70	(70,000)	16.35
Outstanding at end of year	721,500	$ 26.55	646,000	$ 18.67
Options exercisable at end of year	212,500	$ 22.62	214,000	$ 10.89

The following table summarizes information about unit options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/06	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/06	Weighted-Average Exercise Price
$15.20	31,000	0.5 years	$15.20	19,000	$15.20
$22.45-$23.35	251,500	2.3 years	23.32	193,500	23.35
$28.70-$28.75	399,000	2.2 years	28.75	-	-
$32.00-$33.75	40,000	3.0 years	33.55	-	-
$15.20-$33.75	721,500	2.1 years	$26.55	212,500	$22.62

The Trust records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. The Trust granted 447,000 unit options with an estimated fair value of $1,193,000 ($2.67 per option) using the Black-Scholes option pricing model with the following key assumptions:

Weighted-average risk free interest rate (%)	- 4.1
Expected life (years)	- 2.5
Weighted-average volatility (%)	- 27.0
Dividend yield	- based on the percentage of distributions paid to the Unitholders during the year

8. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $300,000 (2005 - $240,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses and represents the fair value of the services rendered.

As at December 31, 2006, the Trust had an account receivable from Comaplex of $38,000 (December 31, 2005 - $29,000).

The Trust received a management fee from Pine Cliff of $216,000 (2005 - $132,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses and represents the fair value of the services rendered.

As at December 31, 2006, the Trust had an account receivable from Pine Cliff of Nil (December 31, 2005 - $165). As at December 31, 2006, the Trust had an account payable of Nil (December 31, 2005 - $16,000) to Pine Cliff. The 2005 amount owing was related to outstanding post closing adjustment items for the sale of properties to Pine Cliff (see Note 3).

9. FINANCIAL INSTRUMENTS

Fair Values

The Trust's financial instruments included in the balance sheet are comprised of accounts receivable, distribution payable, accounts payable and accrued liabilities and the revolving demand loan. The fair value of these financial instruments approximate their carrying value due to the short-term maturity of those instruments. Borrowings under bank credit facilities are for short periods with variable interest rates, thus, carrying values that approximate fair value.

Credit Risk

Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of associated credit risks.

Interest Rate Risk

The Trust's bank debt is comprised of revolving loans at variable rates of interest, and as such, the Trust is exposed to interest rate risk.

Commodity Price Risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices and exchange rates. The Trust monitors and when appropriate uses derivative financial instruments to manage its exposure to these risks.

10. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The Trust entered into the following commodity hedging transactions in 2006 for a portion of its 2007 and 2008 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $74.55 and ceiling of $85.00 per barrel
January 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $95.47 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $93.00 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $70.00 and ceiling of $80.06 per barrel
November 1, 2006 to March 31, 2007	Natural Gas	2,000 GJ's	AECO	Floor of $6.65 and ceiling of $12.50 per GJ
December 1, 2006 to March 31, 2007	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.65 per GJ
April 1, 2007 to July 31, 2007	Natural Gas	2,000 GJ's	AECO	$6.52 per GJ
April 1, 2007 to October 31, 2007	Natural Gas	1,000 GJ's	AECO	Floor of $6.50 and ceiling of $9.20 per GJ
November 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of $6.50 and Ceiling of $10.37 per GJ

As at December 31, 2006 the fair value of the outstanding commodity hedging contracts was a net asset of $1,189,000 (December 31, 2005 – ($1,349,000)).

The Trust has no contractual obligations that last more than a year other than its office lease agreement which is as follows:

Contract Obligations	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Office lease	$1,963,000	$283,000	$910,000	$656,000	$114,000

Trust Information

Board of Directors

G.J. Drummond, Nassau, Bahamas

G.F. Fink, Calgary, Alberta

C.R. Jonsson, Vancouver, British Columbia

F. W. Woodward, Calgary, Alberta

Officers

G.F. Fink – President & Chief Executive Officer

R.M. Jarock – Chief Operating Officer

G.E. Schultz – Vice President, Finance,
Chief Financial Officer & Secretary

Registrar & Transfer Agent

Olympia Trust Company, Calgary, Alberta

Auditors

Deloitte & Touche LLP, Calgary, Alberta

Solicitors

Borden Ladner Gervais LLP Calgary, Alberta

Bankers

The Royal Bank of Canada, Calgary, Alberta

Stock Listing

The Toronto Stock Exchange, Toronto, Ontario

Trading symbol: BNE.UN

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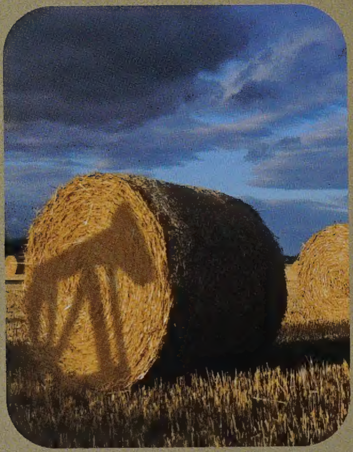

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